BC hydro

The Cost of New Electricity Supply in British Columbia

Resource Planning
Corporate and Environmental
Affairs

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FOREWORD

This report provides information on the cost of obtaining new electricity supply in British Columbia. It is an update of B.C. Hydro's report on the Value of Electricity prepared in August 1989.

Electricity has two components, energy and capacity. In the context of this report, the cost of electricity is based on supplying firm energy and capacity. The value of non-firm or secondary energy is analysed separately. The cost of new electricity supply in British Columbia, indicates the cost that B.C. Hydro would avoid if electricity was obtained from an alternative source and therefore is representative of the value to B.C. Hydro of that electricity. As such, B.C. Hydro uses these costs as a proxy for the value of electricity.

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THE COST OF NEW ELECTRICITY SUPPLY

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SUMMARY

This document provides information on the expected cost of obtaining new electricity supply in British Columbia. The cost is based on the choice and timing of projects and strategies described in B.C. Hydro's 1990 Electricity Plan. In the near-term, when the development schedules are fixed, the cost is determined from the average cost of obtaining additional electricity from existing or committed resources. In the longer term, the cost is determined from the average cost of supplying electricity from new resources included in the 1990 Electricity Plan.

The Cost of New Electricity is the cost of new firm energy supply plus the cost of new capacity.

The cost of new electricity supply depends on the timing of the demand. Being able to serve additional demands during peak hours requires additional investment in generation and transmission capacity. Furthermore, the magnitude of the daily peak demand varies by season. In British Columbia, the demand for electricity is greatest in the winter months. The cost of serving demands during off-peak hours is effectively the cost of supplying firm energy only. The cost of serving demands during peak hours is not only the cost of firm energy but also the cost of capacity. For this reason, the cost of new electricity supply is separated into its component costs for firm energy and capacity.

The location of the demand can also have a significant impact on the cost of new electricity supply. Roughly 70 percent of the demand on the B.C. Hydro system occurs in the Lower Mainland and Vancouver Island regions. The cost of transmission into the Lower Mainland and to Vancouver Island contributes significantly to the cost of serving new demands in these areas. The cost of new electricity supply delivered to the Lower Mainland is provided in Exhibits 1 and 2. The costs of the two components of electricity, firm energy and capacity are also provided.

All costs are quoted in uninflated October 1990 dollars. Exhibit 1 provides the formula used to convert the cost of capacity from $/kW to ¢/kW.h.

The Cost of New Electricity delivered to the Lower Mainland is expected to increase from 2.0 ¢/kW.h in 1990 to 6.4 ¢/kW.h by 2002.

This information is used for the preliminary economic evaluation of resource acquisitions such as Power Smart programs, improvements to the existing system through the Resource Smart programs, non-utility generation projects and B.C. Hydro's future development options. The total cost of a resource alternative is compared to the avoided cost of new electricity supply. Power Smart and Resource Smart projects which have negligible environmental impact are given an environmental credit by reducing their total cost by up to 15 percent in the economic screening test. In addition, B.C. Hydro will continue its qualitative assessment of the environmental impacts of all resource options.

EXHIBIT 1

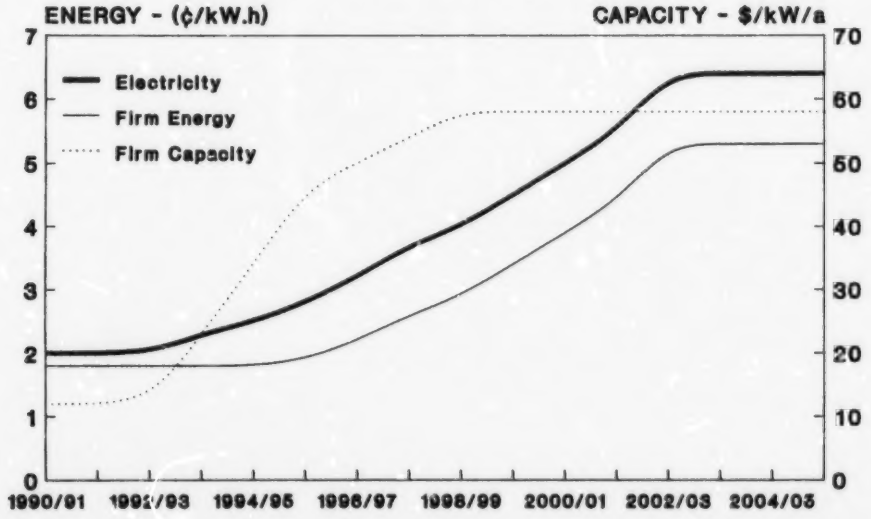
COST OF NEW ELECTRICITY SUPPLY DELIVERED TO THE LOWER MAINLAND
October 1990 Dollars

	Electricity[1] (¢/kW·h)	Firm Capacity $/kW/a	Energy (¢/kW·h)
1990/91	2.0	12	1.8
1991/92	2.0	12	1.8
1992/93	2.0	12	1.8
1993/94	2.3	23	1.8
1994/95	2.5	34	1.8
1995/96	2.8	46	1.9
1996/97	3.2	50	2.2
1997/98	3.7	54	2.6
1998/99	4.0	58	2.9
1999/00	4.5	58	3.4
2000/01	5.0	58	3.9
2001/02	5.5	58	4.4
2002/03 on	6.4	58	5.3

[1] The capacity factor of the B.C. Hydro system is about 65% or 58% after allowing for a 12% reserve margin. Therefore, on average each kW of installed capacity would produce 5080 kW.h/year (0.58 kW x 8760 hours/year). Based on these values a capacity cost of $1/kW/year is equivalent to 1/5080 = 0.0197¢/kW.h.

EXHIBIT 2

COST OF NEW ELECTRICITY SUPPLY
Delivered To The Lower Mainland



1.0 INTRODUCTION

This report provides the cost of new firm energy supply and new capacity supply. These are combined to provide the cost of new electricity supply. The value of secondary (ie. non-firm) energy production is also provided. B.C. Hydro uses these costs to assess the economic viability of various investments, such as:

i) new development options including demand-side management programs,

ii) modifications to existing facilities,

iii) proposed energy purchases and coordination agreements, and

iv) the optimization of resource developments.

This information is offered to other parties interested in the future supply of electricity in B.C.

These costs should be used as a screening tool only. Also, the user should be mindful that these costs are based on the development options identified in the 1990 Electricity Plan. Alternatives which would significantly change the 1990 Electricity Plan require further study.

Whereas using the cost of new electricity may be adequate for some preliminary evaluations, most analyses involve the use of the cost of firm energy, the cost of new capacity and the value of secondary energy.

Transmission losses between the source of supply and the demand affect the cost of both energy and capacity. The cost of new major transmission capacity affects the cost of new capacity. This year, for the first time, the cost of new electricity and its components are provided on a regional basis in order to explicitly demonstrate the impact of transmission on supply costs. This report also considers the daily and monthly variations in the cost of new supply. These concepts have been developed in conjunction with the Transmission Planning Department and are also reflected in B.C. Hydro's wheeling policy.

Section 2 provides an overview of the assumptions and key concepts used in the development of the cost of new electricity supply. Section 3 examines the cost of supplying electricity to the Lower Mainland. Section 4 addresses the regional and peak vs off-peak variations in the costs of new supply. Section 5 discusses the application of this cost information to resource acquisition decisions. The economic screening of resource alternatives is described.

Appendix A provides a detailed description of the methodology used by B.C. Hydro to compute the unit cost of firm energy for individual projects. It includes a calculation of the unit cost of firm energy for the Peace Site C project. Appendix B contains examples of how the information in this report is used to evaluate resource acquisitions. Appendix C explains the calculation of levelized costs which can be used to simplify the evaluation of resource acquistions.

2.0 ASSUMPTIONS and KEY CONCEPTS

2.1 The Components of Electricity

In the context of this report, the cost of electricity is based on supplying firm energy (kilowatt.hours) and capacity (kilowatts) to the major demand centre, the Lower Mainland. Secondary or non-firm energy supply is analyzed separately.

A generating plant's firm energy is its assured annual energy contribution. For B.C. Hydro projects the firm energy capability is based on their average annual energy available during the system's worst historical period of drought which occurred from October 1940 to April 1946.

In general, a project's capacity is the maximum ouput that it can achieve at any point in time. Section 4.2 provides further details on how a project's capacity contribution is determined.

Future increases in demand for electricity that occur during peak periods determine the need for expansion of both the generation and transmission

capacity of the system. Off-peak demands for electricity are generally less costly to serve because they do not trigger the need for additional capacity. Because of these differences, B.C. Hydro prepares estimates of the cost of supplying new capacity as well as new firm energy.

The cost of new electricity supply was calculated by adding the cost of new capacity and the cost of new firm energy. The annual cost of capacity was converted to an equivalent ¢/kW.h value using the B.C. Hydro system load factor of 58 percent (65% actual load factor reduced by the 12% required reserve margin).

2.2 The 1990 Electricity Plan

In May 1990, B.C. Hydro issued its 1990 Electricity Plan which outlines the company's development options and strategy for meeting future electricity needs. The projects included in the Plan provide the basis for estimating the long-term cost of new electricity supply in B.C.

The costs provided in this report are only valid for incremental changes to the supply strategy provided in the Electricity Plan.

Cost estimates for the projects included in the 1990 Electricity Plan are based on the most recent information provided to Resource Planning by B.C. Hydro's System Development Group. These cost estimates were provided in October 1989 dollars and inflated to 1990 dollars using a 5% inflation factor.

2.3 Regional Transmission Losses and Costs

The Transmission Planning Department has analysed the transmission losses and future costs associated with supplying electricity to or from several regions within the province on the major transmission system (predominantly the 500 kV system, 230 kV in some interior regions). Exhibit 3 shows the geographic boundaries of the various regions and the average major transmission system losses for new supplies located in each region. The Lower Mainland is the reference point since it is B.C. Hydro's largest load centre. Exhibit 4 shows the costs of expanding the major transmission network to allow greater capacity transfers between the regions.

2.4 Secondary Energy

Secondary energy is the non-firm component of a generation project's energy production. For example, a hydroelectric project may produce secondary energy during better streamflow years. The value of secondary energy is estimated by adding an increment of secondary energy to a simulation study of the B.C. Hydro system and identifying its impact on system operating costs and on revenues from interruptible sales. Additional secondary energy can be used to:

i) reduce Burrard or other thermal generation,

ii) reduce electricity purchases,

iii) increase exports or other interruptible sales, or

iv) increase spill at hydroelectric reservoirs (i.e. no value).

The average reduction in system operating costs caused by the increment of secondary energy is used to determine the value of new supplies of secondary energy. Exhibit 5 provides the value of secondary energy supplied to the Lower

Exhibit 5

	Value of Secondary Energy Delivered to the Lower Mainland
1990/91	1.1¢/kW.h
1991/92	1.1
1992/93	1.1
1993/94	1.1
1994/95	1.1
1995/96	1.1
1996/97	1.4
1997/98	1.6
1998/99	1.8
1999/00	2.0
2000/01+	2.1

Mainland. These values can be adjusted by transmission losses to derive the value of secondary energy supplied to the other regions.

2.5 The Discount Rate

B.C. Hydro, in consultation with the provincial government, has adopted an 8% discount rate, net of inflation, to evaluate its development strategies. This rate reflects the average pre-tax return on public and private investment in the economy.

The discount rate is used to convert revenues and expenditures occurring in different periods to a common present value basis. It is a critical parameter in project comparisons, particularly when the projects have different construction periods, service lives, or proportion of capital to operating costs.

2.6 Taxes

B.C. Hydro pays water rental fees, grants and school taxes to provincial and municipal governments. From the overall provincial perspective, taxes can be considered as a transfer of money from B.C. Hydro to the province and are not a cost in an economic sense. However, taxes are a real cost from B.C. Hydro's financial perspective and therefore are included in these estimates of the cost of new electricity supply.

It is recognized that additional analysis may be required to evaluate development options from a provincial perspective or to assess the tax implications of non-utility generation.

2.7 Environmental Costs

Only actual expenditures related to environmental impacts, such as the cost of mitigation programs and pollution control equipment, have been included in the estimate of the cost of new electricity supply provided in this report. Therefore, in order to compare the cost of electricity from alternative development options to the cost of new electricity supply, only these costs should be included.

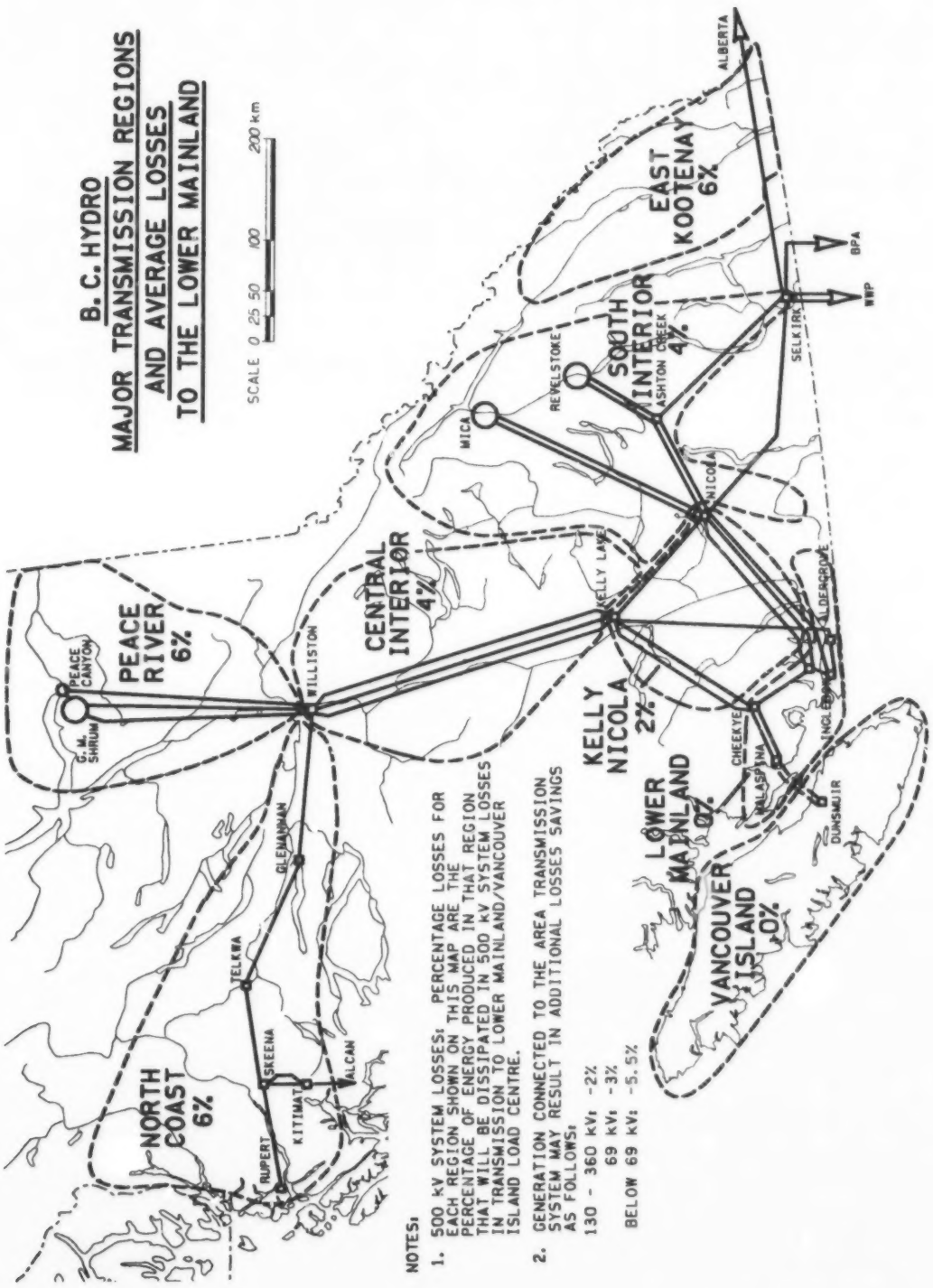
Along with many other North American utilities, B.C. Hydro is working towards incorporating the impact of environmental externalities into the resource ranking and selection process. Environmental externalities are those costs which are not incorporated into the cost of a project, such as the effects on land use, wildlife, or air quality.

The preference order for development options, as provided in the 1990 Electricity Plan, resulted from a qualitative ranking which included consideration of environmental externalities. Power Smart programs were ranked as the first priority followed by Resource Smart, small hydro and waste-wood fired generation, hydro projects in developed river basins and lastly, hydro projects in undeveloped basins and new thermal generation.

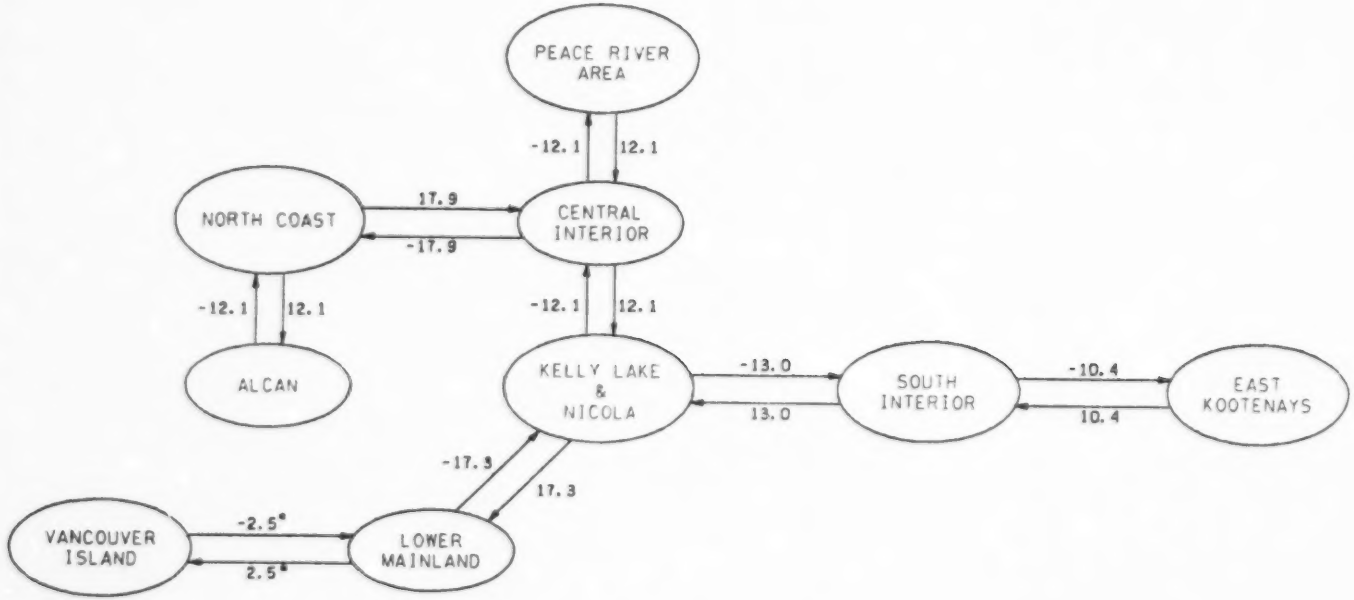
B.C. Hydro will continue to use qualitative judgement with respect to environmental impacts in the assessment of resource options. However, in order to recognize the preference for Power Smart and Resource Smart projects which have no environmental impact, it is proposed that an environmental credit of 15 percent be applied to the cost of these projects in order to compare them to the cost of new electricity supply. This credit would be reduced if there is some environmental impact associated with the project. Further details are provided in section 5 of this report.

This credit is consistent with the provincial government's Special Direction to the B.C. Utilities Commission endorsing environmental premiums for electricity generation projects which offer environmental benefits.

EXHIBIT 3


B. C. HYDRO
MAJOR TRANSMISSION REGIONS
AND AVERAGE LOSSES
TO THE LOWER MAINLAND
SCALE 0 25 50 100 200 km
NORTH COAST 6%
PEACE RIVER 6%
CENTRAL INTERIOR 4%
SOUTH INTERIOR 4%
EAST KOOTENAY 6%
KELLY NICOLA 2%
LOWER MAINLAND 0%
VANCOUVER ISLAND 0%
PEACE CANYON
S.M. SHRUM
WILLISTON
TELKWA
GLENANNAN
SKEENA
KITIMAT
ALCAN
RUPERT
MICA
REVELSTOKE
ASHTON CREEK
NICOLA
KELLY LAKE
SELKIRK
ALBERTA
BPA
WWP
CHEEKYE
DUNSMUIR
NOTES:
1. 500 kV SYSTEM LOSSES: PERCENTAGE LOSSES FOR EACH REGION SHOWN ON THIS MAP ARE THE PERCENTAGE OF ENERGY PRODUCED IN THAT REGION THAT WILL BE DISSIPATED IN 500 kV SYSTEM LOSSES IN TRANSMISSION TO LOWER MAINLAND/VANCOUVER ISLAND LOAD CENTRE.
2. GENERATION CONNECTED TO THE AREA TRANSMISSION SYSTEM MAY RESULT IN ADDITIONAL LOSSES SAVINGS AS FOLLOWS:
130 - 360 kV: -2%
69 kV: -3%
BELOW 69 kV: -5.5%

B. C. HYDRO MAJOR TRANSMISSION SYSTEM
LONG-TERM TRANSMISSION COSTS/CREDITS FOR DOMESTIC SUPPLY
(IN OCT 1990 $/kW/YR)



* IN THE LONGER TERM (PAST 2005) THESE VALUES INCREASE TO 35.8

3.0 THE COST OF NEW FIRM ENERGY AND CAPACITY

3.1 The Cost of New Capacity Supply

In the short-term, the cost of serving additional demands for capacity is based on its value in the export market. System Operations and Maintenance Division has estimated this value at $12/kW/year for the Lower Mainland and Vancouver Island.

Between 1992/93 and 1998/99 the cost of new capacity is based on the cost of transmission system expansions planned for that period as determined by the Transmission Planning Department.

The long-term cost of new generation capacity is derived from the least cost peaking capacity alternative available. That would be additional units at Mica and Revelstoke. If no new generation were added, this additional peaking capacity would be required in 1998/99 at an estimated cost of $25.7/kW/year.

The cost of transmitting capacity from the South Interior region, where these projects are located, to the Lower Mainland would be $30.3/kW/year and the transmission losses would be 4% (see Exhibits 3 and 4). Therefore, the long-term cost of additional capacity supplied to the Lower Mainland is $58/kW/year.

It is important to note that the Electricity Plan does not include the installation of these additional units at Mica and Revelstoke because other generation projects required to provide firm energy will also provide capacity.

3.2 The Cost of New Firm Energy

Systems Operations and Maintenance Division has estimated the cost of supplying additional firm energy at the Lower Mainland for the next 3 years at 1.8¢/kW.h. This cost is influenced by the volatility of streamflow conditions and export markets as well as the cost of natural gas supply for the Burrard generating station.

Beyond 1992, the cost of new firm energy supply is obtained by adding an increment of firm energy demand, over and above the expected annual increase in demand, to a simulation study of the existing and committed B.C. Hydro system. These simulation studies indicate that the cost of supplying that incremental demand without adding new resources increases over time and that by the turn of the century it exceeds the cost of adding new resources. Therefore, after the turn of the century, the cost of new firm energy supply was determined from the average cost of adding

EXHIBIT 6

Long Term Cost of Firm Energy Delivered to the
Lower Mainland From Projects Included in the 1990 Electricity Plan

	Unit cost of firm energy (¢/kwh)	Weighting Factor based on firm energy
Peace Site C	4.9	47.9
Keenleyside	5.5	9.4
Border	6.1	15.8
Murphy	6.1	15.2
Waneta	4.1	5.6
Seven Mile Unit 4	2.0	1.5
Brilliant	5.0	4.6

WEIGHTED AVERAGE: 5.3¢/kW.h delivered to the Lower Mainland

the new resources identified in the 1990 Electricity Plan.

The 1990 Electricity Plan identified the Peace Site C project plus several projects on the Lower Columbia River as the most economic resource development options available to B.C. Hydro. Exhibit 6 shows the unit cost of firm energy supplied to the Lower Mainland from these projects.

Since these projects are also considered to be representative of the developments which would follow in 2010 and beyond, their weighted average unit cost of firm energy has been used to estimate the cost of new firm energy supply for the long term.

The estimated long-term cost of firm energy delivered to the Lower Mainland is 5.3 ¢/kw.h.

Appendix A provides further details on the methodology used to derive the cost of firm energy for individual projects delivered to the Lower Mainland.

3.3 The Cost of New Electricity Supply

The cost of new electricity combines the cost of new firm energy and the cost of new capacity. The cost of capacity in $/kW is converted to ¢/kW.h using the B.C. Hydro system capacity factor of 65 percent adjusted for the required reserve margin of 12 percent, or 58% Therefore, on average, 1 kW produces .58 x 8760 hours/year or 5080 kW.h/year and $1/kW/year = !/5080 = 0.0197¢/kW.h. As a result, the long term cost of capacity delivered to the Lower Mainland of $58/kW/year is equivalent to 1.1¢/kW.h.

The estimated long-term cost of electricity delivered to the Lower Mainland is 6.4¢/kw.h.

The cost of new electricity supplied to the Lower Mainland and its components, firm energy and capacity, are provided in Exhibit 1 and illustrated graphically in Exhibit 2. These exhibits are on page 2 of the Summary.

4.0 THE IMPACTS OF LOCATION OF SUPPLY AND PEAK vs OFF-PEAK DEMANDS

4.1 The Cost of New Electricity Supply by Region

The cost of transmission and the effects of transmission losses create regional differences in the cost of new electricity supply.

Exhibit 7 provides the cost of new firm energy and capacity supply as well as the resultant cost of new electricity supply for each of the regions identified in Exhibit 3. These results indicate the cost of serving an increase in demand in these regions. Therefore, they also indicate the value to B.C. Hydro of an incremental increase in generation supply or reductions in demand in these regions.

The losses shown in Exhibit 3 and the transmission costs and/or credits provided in Exhibit 4 were used to derive these values.

The cost of firm energy supplied to the Lower Mainland (Exhibit 1) was adjusted by the transmission losses to determine the cost of supplying firm energy in the other regions.

As noted in section 3.1, the short term cost of capacity in the Lower Mainland and Vancouver Island has been estimated at $12/kW/year. In the other regions, sufficient generation and transmission capacity exist to meet incremental capacity demands over the next three years without incurring additional cost. Furthermore, additional capacity available outside the Lower Mainland and Vancouver Island can not be used to take advantage of present export opportunities because of transmission restrictions. Therefore, the short term cost of new capacity supply in all regions outside the Lower Mainland and Vancouver Island is zero.

Between 1992/93 and 1998/99 the cost of new capacity for each region is based on the cost of transmission system expansions planned for that period as estimated by the Transmission Planning Department.

The long term cost of new capacity in and beyond 1998/99 for all regions is based on B.C. Hydro's least expensive capacity option, additional capacity at Mica and Revelstoke. As previously noted, the average cost of Mica and Revelstoke additional generation capacity is $25.7/kW/year. The cost of transmission from the South Interior was calculated for each region. For some regions, the transmission of capacity from the Southern Interior would be opposite the flow of capacity towards the Lower Mainland resulting in a transmission credit and reduced transmission losses.

The regional values for the cost of electricity should be used to evaluate the electricity savings from Power Smart programs in the various regions. The regional values should also be used to evaluate near-term resource options such as non-utility generation projects, and Resource Smart projects, in order to reflect the regional differences in the near-term cost of new capacity.

EXHIBIT 7
THE COST OF NEW ELECTRICITY SUPPLY BY REGION

	LOWER MAINLAND	NORTH COAST	PEACE RIVER	EAST KOOTENAY	CENTRAL INTERIOR	SOUTH INTERIOR	KELLY LAKE/ NICOLA	VANCOUVER ISLAND
COST OF NEW FIRM ENERGY (c/kW.h):								
1990/91	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.8
1991/92	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.8
1992/93	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.8
1993/94	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.8
1994/95	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.8
1995/96	1.9	1.8	1.8	1.8	1.8	1.8	1.9	1.9
1996/97	2.2	2.1	2.1	2.1	2.1	2.1	2.2	2.2
1997/98	2.6	2.4	2.4	2.4	2.4	2.5	2.5	2.6
1998/99	2.9	2.7	2.7	2.7	2.8	2.8	2.8	2.9
1999/00	3.4	3.2	3.2	3.2	3.3	3.3	3.3	3.4
2000/01	3.9	3.7	3.7	3.7	3.7	3.7	3.8	3.9
2001/02	4.4	4.1	4.1	4.1	4.2	4.2	4.3	4.4
2002/03+	5.3	5.0	5.0	5.0	5.1	5.1	5.2	5.3
COST OF NEW CAPACITY ($/kW):								
1990/91	12	0	0	0	0	0	0	12
1991/92	12	0	0	0	0	0	0	12
1992/93	12	0	0	0	0	0	0	12
1993/94	23	5	2	4	7	4	10	24
1994/95	34	8	8	6	14	9	16	36
1995/96	46	8	14	8	21	13	22	49
1996/97	50	8	14	10	23	17	28	53
1997/98	54	9	14	12	25	21	34	57
1998/99	58	9	14	15	27	26	40	61
1999/00	58	9	14	15	27	26	40	61
2000/01	58	9	14	15	27	26	40	61
2001/02	58	9	14	15	27	26	40	61
2002/03	58	9	14	15	27	26	40	61
2003/04	58	9	14	15	27	26	40	61
2005/06+	58	9	14	15	27	26	40	96
COST OF NEW ELECTRICITY SUPPLY (c/kW.h):								
1990/91	2.0	1.7	1.7	1.7	1.7	1.7	1.8	2.0
1991/92	2.0	1.7	1.7	1.7	1.7	1.7	1.8	2.0
1992/93	2.0	1.7	1.7	1.7	1.7	1.7	1.8	2.0
1993/94	2.3	1.8	1.7	1.8	1.9	1.8	2.0	2.3
1994/95	2.5	1.8	1.8	1.8	2.0	1.9	2.1	2.5
1995/96	2.8	1.9	2.1	1.9	2.2	2.1	2.3	2.9
1996/97	3.2	2.2	2.3	2.3	2.6	2.4	2.7	3.2
1997/98	3.7	2.6	2.7	2.7	3.0	2.9	3.2	3.7
1998/99	4.0	2.9	3.0	3.0	3.3	3.3	3.6	4.1
1999/00	4.5	3.4	3.5	3.5	3.8	3.9	4.1	4.6
2000/01	5.0	3.9	3.9	4.0	4.3	4.2	4.6	5.1
2001/02	5.5	4.3	4.4	4.4	4.7	4.7	5.1	5.6
2002/03	6.4	5.2	5.3	5.3	5.6	5.6	6.0	6.5
2003/04	6.4	5.2	5.3	5.3	5.6	5.6	6.0	6.5
2005/06+	6.4	5.2	5.3	5.3	5.6	5.6	6.0	7.2

EXAMPLE: The long-term cost of new firm energy in the North Coast region is the Lower Mainland cost adjusted for the avoided losses of 6 percent: 5.3¢/kW.h x (1-0.6) = 5.0¢/kW.h
A transmission credit of $17/kW/year (Exhibit 4) and avoided losses of 2 percent (Exhibit 3) are applicable between the South Interior and the North Coast regions. Therefore, the long term cost of new capacity in the North Coast is $(25.7-17)/kW/year x (1-.02) = $9/kw/year.
The cost of new electricity supply = 5.0 + ($9/kW x 0.0197¢/kW.h) = 5.2¢kW.h (see section 3.3).

4.2 Peak versus Off-Peak Capacity Supply Costs

As previously noted, the cost of supplying additional electricity during peak periods is the cost of firm energy plus the cost of capacity. The cost of new capacity provided in this report is the annual cost B.C. Hydro expects to incur in order to be able to provide sufficient capacity to meet peak demands. However, a more detailed evaluation of the cost of capacity may be required to evaluate the actual capacity contribution of an alternative supply which can not be dispatched by B.C. Hydro to meet system requirements or which can not sustain its output during periods of peak demand. This requires a month-by-month determination of the project's capacity contribution and consideration of the monthly variation in the cost of capacity supply.

The daily peak period on the B.C. Hydro system, also referred to as the heavy load hours, is from 7 a.m. to 8 p.m. on weekdays, excluding holidays. This is an average 270.5 hours per month, or 37 percent of the time.

Since the B.C. Hydro system is winter peaking, the cost of providing additional capacity is greater during the winter months. This is reflected in the following monthly weighting factors for the cost of capacity which are consistent with B.C. Hydro's wheeling policy.

MONTHLY WEIGHTING FACTORS FOR CAPACITY	
January	1.5
February	1.5
March	1.0
April	1.0
May	0.5
June	0.5
July	0.5
August	0.5
September	1.0
October	1.0
November	1.5
December	1.5

The following outlines how projects are categorized in order to calculate their capacity contribution:

Dispatchable with monthly capacity factor greater than 37% If the output of a project is controllable by B.C. Hydro to meet system requirements, then the value of that project's capacity in the months in which its output can be sustained during heavy load hours is 1/12th of the annual cost of new capacity x the monthly weighting factor x the project capacity. If this is true for all 12 months, then the value of the project's capacity equals the annual cost of new capacity.

Dispatchable but monthly capacity factor less than 37% In the months that a dispatchable project's output can not be sustained through the heavy load hours, the value of its capacity is calculated as its firm energy output for that month divided by the number of heavy-load-hours in the month and adjusted by the monthly weighting factor.

Not Dispatchable by B.C. Hydro: A monthly estimate of firm energy production during heavy-load-hours would have to be provided for this type of project. This would be used to calculate the average MW output during heavy-load-hours. The value of the project's capacity for each month would then be calculated as the average MW x 1/12th of the annual cost of new capacity x the monthly weighting factor.

5.0 APPLICATION TO RESOURCE ACQUISITION DECISIONS

The cost of new firm energy and capacity assumes the development of the major hydroelectric projects identified in the 1990 Electricity Plan. Therefore, these are the costs B.C. Hydro would avoid if firm energy and capacity were acquired from alternative sources. The cost information provided in this report is used in the economic screening of resource options. Costs and benefits are discounted over the project's duration, at an 8% (net) discount rate.

Resource acquisitions could include purchases from non-utility generators (independent power producers and customer self-generation), Power Smart programs, Resource Smart projects and alternative major development options.

5.1 Evaluation of Non-Utility Generation Projects

Non-utility generation projects include independent power producer projects and customer self-generation or load-displacement projects. The cost of new firm energy and capacity provides non-utility generators with the "ceiling price" for their projects. The ceiling price is a guideline only. It does not supplant the contract negotiation process and it does not acccount for environmental factors.

The value to the B.C. Hydro system of a non-utility generator is affected by transmission costs and transmission losses. This is reflected in the regional costs of new firm energy and capacity supply provided in Exhibit 7. It is recommended that Exhibit 7 be used to evaluate non-utility generation projects.

Because the cost of new firm energy and capacity is expected to increase annually until after the turn of the century, the value of a non-utility generator's contribution will vary depending on the contract period. Equivalent uniform (or "levelized") costs of new energy and capacity for specified contract periods can be used to simplify the evaluation of non-utility generation projects. An explanation of levelized costs and their use is provided in Appendix C. The equivalent "levelized" costs of energy and capacity are provided for a range of start dates and contract periods for the various regions.

Since B.C. Hydro must have sufficient capacity to meet peak demands as they occur, the cost of new capacity may not be fully avoided by purchasing capacity from a non-utility generator. Refer to section 4.2 to determine the value of a non-utility generator's capacity contribution. Exhibit B-1 provides a calculation of the effective annual value of capacity from a non-utility generator both as a dispatchable project and a non-dispatchable project.

The environmental impacts of proposed non-utility generation projects are assessed by the Ministry of the Environment as an important aspect of the project screening process.

5.2 Evaluation of Power Smart Programs

Power Smart programs are intended to achieve permanent reductions in electricity consumption by B.C. Hydro customers, mainly through the introduction of efficiency measures. The economic evaluation of Power Smart programs examines whether or not the total program cost is less than the cost of supplying the equivalent amount of electricity. A preliminary economic evaluation would use the cost of electricity supply by region provided in Exhibit 7. However, reductions in demand during peak periods and during the winter months are more valuable. Therefore, a more detailed economic screening would consider the timing of the energy savings by month and by peak versus off peak hours.

Costs and energy savings are discounted over the program's duration, at an 8% (net) discount rate. Each program should be assessed separately unless it is interdependent (bundled) with others. The cost of new electricity supply incorporates losses only on the major transmission system. Therefore, additional credit should be assessed if distribution line losses are also avoided.

As noted in section 2.7, Power Smart projects which have little or no environmental impacts are

given an environmental credit. The environmental credit is applied by reducing the project costs by up to 15 percent in order to compare these projects to the cost of new supply. This environmental credit provides guidance for the screening of Power Smart programs. Other factors may influence the decision whether or not to proceed with a particular program.

Exhibit B-2 shows the evaluation of a Power Smart program in two different regions. An industrial sector program which would have no impact on distribution system losses, and no environmental impact was assumed. The total cost of achieving the expected electricity savings is compared to the cost of new supply. This is also referred to as the Total Resource Cost Test.

5.3 Resource Smart Projects

Resource Smart projects are undertaken by B.C. Hydro to enhance the contribution from existing generation and transmission facilities. The costs and benefits of a Resource Smart project should be evaluated at 8% (net) discount rate over the lifetime of the project. Many Resource Smart projects would have little or no environmental impact so an environmental credit is applied by reducing the project costs by up to 15 percent in order to compare these projects to the cost of new supply.

For example, using the numbers in Exhibit A-3, if this were a Resource Smart project eligible for the full 15% environmental credit then the present worth of the total project cost would be 1511 -15% = 1284 M$. The present worth of costs attributed to firm energy production would be 1284 - 291 - 27 = 966 M$ and the adjusted unit energy cost would be 966/24531 = 3.9¢/kW.h. In order to calculate a benefit-to-cost ratio for such projects the following formula is recommended:

$$\text{Benefit/cost} = \frac{\text{p.w. of firm energy+capacity+secondary energy}}{\text{p.w. of total costs (1-environmental credit)}}$$

The project benefits are calculated using the cost of new supply provided in this report.

As with Power Smart programs, this environmental credit provides guidance for the screening of Resource Smart projects. Other factors may influence the decision whether or not to proceed with a particular project.

The regional data provided in Exhibit 7 should be used to evaluate Resource Smart projects planned for the near-term to more accurately reflect the value of their capacity contribution.

5.4 Major Generation Projects

In B.C. Hydro's evaluation of a proposed generation project, the unit cost of firm energy is calculated as described in Appendix A. Optimization studies are conducted for various components of the project. The cost of the incremental investment is compared to the value of the incremental energy and capacity benefits over the project's service life. These optimization studies are conducted using an 8% (net) discount rate.

Optimizing many of the components of a project would have little or no environmental impact. Therefore, it is recommended that the incremental costs be reduced by the 15% environmental credit. However, it is recognized that this is only a guideline. Sensitivity studies and engineering judgement remain critical aspects in these decisions.

APPENDIX A: CALCULATION OF THE LONG-TERM COST OF NEW FIRM ENERGY FOR INDIVIDUAL PROJECTS

This appendix provides a detailed description of the method used to calculate the cost of new firm energy delivered to the Lower Mainland from individual projects.

This calculation was conducted for the projects identified in the 1990 Electricity Plan, namely the Peace Site C project and 6 projects on the Lower Columbia River. As discussed in Section 3.2 of the report, B.C. Hydro's long-term cost of new firm energy is the weighted average of the unit cost of firm energy from these projects delivered to the Lower Mainland. Section A.2 details the calculation of the unit cost of firm energy for the Peace Site C project, delivered to the Lower Mainland.

A.1 The Unit Cost of Firm Energy for Individual Projects

Most generation projects produce both capacity and firm energy. In addition, many projects also produce secondary (non-firm) energy. Therefore, in order to isolate the cost of firm energy, it is assumed that for each project the cost of firm energy is the total project cost, including a prorated share of the cost of future expansion of the major transmission system to the Lower Mainland, minus credits for the project's capacity and secondary energy contributions. The credits for capacity and secondary energy are adjusted for transmission losses to the Lower Mainland.

The unit cost of firm energy delivered to the Lower Mainland over a project's lifetime is the present value of this cost of firm energy divided by the present value of the firm energy delivered to the Lower Mainland. This computation is referred to as the present worth method.

A.1.1 Project Cost

The project costs include the following:

1. The capital cost of the generation project and the associated transmission. The associated transmission includes only the transmission required to physically connect the project into the existing transmission system. These costs include direct project costs, engineering and contingency allowances. Except for specific mitigation expenses, environmental costs are not included.

   When the generation and transmission portions of the project have different plant lives, the portion with the shorter lifetime is rebuilt in the appropriate year and, if necessary, an adjustment is made to account for salvage value at the end of the total project life. Exhibit A-2 provides the assumed plant life for generation and transmission projects.

   When using the present worth method, interest-during-construction is not included.

2. Overhead. Exhibit A-1 provides the 1990 overhead rates estimated by the Plant Accounting Department for a range of project sizes. These rates should be applied to smaller projects and to projects that will be constructed in the near future. However, since these rates vary over time, an estimated long term corporate overhead rate of 5% is recommended for major projects.

3. To calculate the annual operating costs, the generation and transmission components of the project are treated separately.

There are both fixed and variable components to the annual operating costs associated with generation projects. Exhibit A-2 provides the current basis for estimating generation operating costs. Since projects on the Peace and Columbia rivers are exempt from school taxes, the fixed annual charge as a percent of construction cost is reduced from 1.81% to 0.48% for these projects. The charge for installed capacity and the variable annual charge are the two components of the Annual Water Rental Fee.

Exhibit A-2 also provides the operating costs for the associated transmission.

4. A portion of the cost of new major transmission between the project and the

Lower Mainland is allocated to the project by multiplying the capacity rating of the project times the transmission cost (or credit) provided in Exhibit 4. In this way, the cost of future expansion of the major transmission system is assessed against each new project on a $/kW/year basis.

A.1.2 Credits for Secondary Energy Production and Capacity

Credits for capacity and secondary energy delivered to the Lower Mainland, calculated as follows, are subtracted from the Project Cost:

1. Secondary energy is the difference between the average annual energy and the firm annual energy of the project. The annual credit for secondary energy is the annual secondary output of the project times the value of secondary energy at the Lower Mainland (see Exhibit 5) adjusted by the transmission losses between the project location and the Lower Mainland (see Exhibit 3).
2. If the project is dispatchable by B.C. Hydro and can sustain its capacity output during the periods of peak demand then the credit for capacity delivered to the Lower Mainland is the capacity output of the project times the cost of supplying new capacity at the Lower Mainland (Exhibit 1) adjusted by the transmission losses. Refer to section 4.2 of the main report to assess the capacity credit for projects which do not meet this criterion.

EXHIBIT A-1
CORPORATE OVERHEAD RATES - May 1990

Total Uninflated Direct Cost Range (k$)			Overhead Rate (%)
1	to	8	16.0
9		36	15.0
37		90	14.0
91		173	13.0
174		291	12.0
292		458	11.0
459		700	10.0
701		1,068	9.0
1,069		1,681	8.0
1,682		2,831	7.0
2,832		5,433	6.0
5,434		13,460	5.0
13,461		58,404	4.0
58,405		1,259,144	3.0
1,259,145		10,000,000	2.0

SOURCE: Plant Accounting, 24 May 1990

NOTE: Since these rates vary over time, an estimated long term corporate overhead rate of 5% is recommended for major projects.

EXHIBIT A-2

BASIS FOR ESTIMATING OPERATING COSTS
(October 1990 dollars)

	Hydro	Gas/Oil Thermal	Coal-Fired Thermal	Gas Turbine	Transmission Wood Pole	Transmission Steel
Fixed Annual Charges 1. As a percent of uninflated total construction cost)*1						
Operation and Maintenance	0.45	1.80	0.86	1.47	1.2	0.6
Administration and General Expense	incl.	0.45	incl.	0.13	incl.	incl.
Insurance	0.03	0.03	0.02	0.03	incl.	incl.
School tax & other grants*2	1.33	1.33	1.33	1.33	0.7	1.3
Interim Replacement	incl.	0.35	incl.	incl.	incl.	incl.
TOTAL	1.81	3.96	2.21	2.96	1.90	1.90
2. Charges for Installed Capacity ($/kW)*3	3.35	0.5	0.5	0.5		
Variable Annual Charges*4 (¢/kW.h, 1990)	0.399*5	0.0667	0.015	incl.	—	—
Assumed Plant Life (years)	70	35	35	30	30	45

Notes:
*1 Total construction cost excludes Corporate Overhead and Interest during Construction.
*2 Peace and Columbia River projects are exempt from school taxes.
*3 Water Rental Capacity charge of 2.85 $/kw plus grant-in-lieu of taxes of 0.5 $/kw
*4 Variable annual charges are subject to annual escalation. Fuel costs are additional to variable charges and are to be determined separately for each project.
*5 Energy portion of Water Rental Fees.

A.2 EXAMPLE: Unit Cost of Firm Energy for the Peace Site C Project Supplied to the Lower Mainland

The proposed Site C project is a 900 MW hydroelectric generation project on the Peace River, downstream of the existing Peace Canyon project. It would provide 4570 GW.h of firm energy and an additional 140 GW.h of secondary energy annually. Two 500 kV transmission lines, 76 km in length, would be required to connnect the project to the B.C. Hydro system. The capital cost of the project is estimated to be 1,760 M$ for the generation and 71 M$ for the associated transmission in October 1990 dollars.

Exhibit A-3 provides the detailed calculation of the unit cost of firm energy delivered to the Lower Mainland from the Peace Site C project. The present worth method was used assuming an 8% net discount rate. Uninflated costs, in October 1990 dollars were used.

The first two generating units would be in-service in 2000 and the remaining 4 would be in-service by the end of 2001. The schedule of capital costs includes 1,760 million dollars for the generation project and 71 million dollars for the associated transmission, increased by 5% for overhead.

Peace River projects are exempt from school taxes. Therefore from Exhibit A-2, the annual operating costs of 30.7 M$/year is:

[0.48% x 1,760 M$]+[3.35$/kW/year x 900 MW]+[0.399¢/kW.h x 4710 GW.h] = 30.3 M$/year for the generation, plus

[0.6% x 71 M$] = 0.4 M$/year for the associated transmission.

The portion of the cost of the major transmission system from the Peace River region to the Lower Mainland allocated to the project is the project capacity (900 MW) times the transmission cost of $41.5/kW/year (Exhibit 4).

A project life of 70 years was assumed for the generation project and 45 years for the associated transmission. For the transmission, the cost of rebuilding the line in 45 years and its salvage value in the 70th year were included in the capital cost.

The capacity credit was calculated using the cost of new capacity delivered to the Lower Mainland (Exhibit 1). Similarly, the credit for secondary energy was calculated using the value of secondary energy delivered to the Lower Mainland (Exhibit 5). For a large project, such as Site C, a portion of the project's firm energy is considered as secondary energy during its initial years of operation because the annual load growth can not utilize the full firm energy capability of the project.

The present worth of the total cost was calculated as the present worth of the capital costs including overhead, plus the annual operating costs, plus the annual transmission costs accumulated over the 70 year project life. The annual credits for capacity and secondary energy, accumulated over the project life, were adjusted by the 6% transmission losses between the Peace River region and the Lower Mainland (from Exhibit 3). The unit cost of firm energy of 4.9¢/kW.h is the present worth of the total cost minus credits divided by the present worth of the firm energy produced by the project over its lifetime adjusted for transmission losses to the Lower Mainland.

Exhibit A-3

UNIT COST OF FIRM ENERGY FOR THE PEACE SITE C PROJECT (delivered to the Lower Mainland)
70 YEAR PROJECT LIFE - IN-SERVICE in 2000
(uninflated) OCTOBER 1990 DOLLARS

NET DISCOUNT RATE: 8%
PROJECT LOCATION: Peace River Region

TRANSMISSION LOSSES: 6% (from Exhibit 3)
TRANSMISSION COST: 41.5 $/kW/yr. (from Exhibit 4)

	Project Costs		Transmission Costs to Lower Mainland		Capacity Credit		Secondary Energy Credit			Firm Energy Output
Year	Capital Cost* M$	Annual Operating Cost M$**	Capacity MW	Cost of Transmission M$	$/kW/year see (Exhibit 1)	Credit M$	Secondary Energy GW.h/a	c/kW.h see (Exhibit 1)	Credit M$	GW.h/a
90/91	4	0	0	0	12	0	0	1.1	0	0
91/92	7	0	0	0	12	0	0	1.1	0	0
92/93	7	0	0	0	12	0	0	1.1	0	0
93/94	17	0	0	0	23	0	0	1.1	0	0
94/95	157	0	0	0	34	0	0	1.1	0	0
95/96	204	0	0	0	46	0	0	1.1	0	0
96/97	190	0	0	0	50	0	0	1.4	0	0
97/98	304	0	0	0	54	0	0	1.6	0	0
98/99	466	0	0	0	58	0	0	1.8	0	0
99/00	355	0	0	0	58	0	0	2.0	0	0
00/01	150	13	300	12	58	17	0	2.1	0	840
01/02	55	30	900	37	58	52	1415	2.1	30	3000
02/03	7	31	900	37	58	52	210	2.1	4	4500
03/04	0	31	900	37	58	52	140	2.1	3	4570
04/05	0	31	900	37	58	52	140	2.1	3	4570
					"					
					"					
					"					
65/66	0	31	900	37	58	52	140	2.1	3	4570
67/68	0	31	900	37	58	52	140	2.1	3	4570
68/69	0	31	900	37	58	52	140	2.1	3	4570
69/70	0	31	900	37	58	52	140	2.1	3	4570
70/71	0	30	900	37	58	52	61	2.1	3	3734
71/72	0	13	300	12	58	17	0	2.1	3	234
72/73	-34	0	0	0	58	0	0	2.1	3	0
Present worth:	1107	183		221		309			29	26002

Present Worth of Capital Cost incl. Overhead: 1107 M$
Present Worth of Annual Operating Costs: 183
Present Worth of Transmission Cost to Lower Mainland: 221
TOTAL PRESENT WORTH OF COSTS: = 1511

Present Worth of Capacity Credit: 291 (309 minus 6% losses)
Present Worth of Secondary Energy Credit: 27 (29 minus 6% losses)
Present Worth of Costs Attributed to Firm Energy Production: = 1192 M$

Present Worth of Firm Energy: 24531 GW.h (26 002 minus 6% losses)
UNIT COST OF FIRM ENERGY: 4.9 c/kW.h

* Capital Costs: 1,760 M$ for generation and 71 M$ for associated transmission, plus 5% overhead. Transmission is replaced after project life of 45 years. A salvage value is included in 2072/73 to account for remaining life.
** Generation O&M based on Exhibit A-2, Transmission O&M based on Exhibit A-2
NOTE: Peace and Columbia River projects are exempt from school taxes.

APPENDIX B APPLICATION TO RESOURCE ACQUISITIONS

Exhibit B-1 provides the calculation of the effective annual capacity contribution from a non-utility generator as discussed in section 5.1. First it is assumed that the project is dispatchable by B.C. Hydro and then it is assumed that the project is not dispatchable.

Exhibit B-2 provides an evaluation of a Power Smart program as discussed in Section 5.2.

EXHIBIT B-1

NON-UTILITY GENERATOR - CAPACITY CONTRIBUTION FROM A DISPATCHABLE vs NON-DISPATCHABLE PROJECT

Assumptions: - 150MW installed capacity
- Lower Mainland location
- 20 year contract starting in 1996/97
- levelized annual cost of capacity = $57/kW from Exhibit C-2 = $4750/MW/month

			Assumed Project Output		Calculation of the Project's Capacity Contribution				
					Dispatchable Project			Non-Dispatchable Project	
	Monthly Weighting Factor	Cost of Capacity $/MW/Month	Monthly Firm Energy Schedule GW.h	Firm Energy Schedule During Heavy Load Hours	Monthly Capacity Factor %	Effective Capacity (MW)	Value of Capacity Contribution K$	Average MW During Heavy Load Hours	Value of Capacity Contribution K$
Jan.	1.5	7125	20	7	0.18	74[1]	528[3]	26[4]	184
Feb.	1.5	7125	20	7	0.18	74	528	26	184
Mar.	1	4750	20	7	0.18	74	352	26	123
Apr.	1	4750	20	7	0.18	74	352	26	123
May	0.5	2375	50	19	0.46	150[2]	356	70	167
June	0.5	2375	100	37	0.91	150	356	137	325
July	0.5	2375	100	37	0.91	150	356	137	325
August	0.5	2375	100	37	0.91	150	356	137	325
Sep.	1	4750	100	37	0.91	150	713	137	650
Oct.	1	4750	100	37	0.91	150	713	137	650
Nov.	1.5	7125	100	37	0.91	150	1069	137	975
Dec.	1.5	7125	50	17	0.46	150	1069	63	448
Annual Totals:							6748		4478
Effective Annual Value of Capacity $/kW/year:							45		30

NOTES:
(1) For a dispatchable project with a monthly capacity factor <37%, EFFECTIVE CAPACITY = (Monthly firm energy/270.5 HLH per month).
(2) If monthly capacity factor > 37%, EFFECTIVE CAPACITY = 150 MW.
(3) Value of Monthly Capacity Contribuiton = Effective Capacity x monthly cost of capacity.
(4) For a non-dispatchable project the effective capacity is the average MW during heavy load hours which equals firm energy during HLH/270.5 HLH per month.

EXHIBIT B-2

EVALUATING THE COST EFFECTIVENESS OF POWER SMART PROGRAMS

using the TOTAL RESOURCE COST TEST

15% ENVIRONMENTAL CREDIT APPLIED TO THE PROGRAM COST

PROGRAM: an industrial energy savings program with no environmental impacts
LOCATION: Case 1 - Lower Mainland region
Case 2 - East Kootenay region

ANNUAL BENEFITS based on Regional Cost of Electricity (Exhibit 7)
DISCOUNT RATE: 8% (net)

Year	Total Costs k$	Total Costs Reduced 15%	Electricity Savings GW.h/yr	CASE 1: POWER SMART SAVINGS FROM LOWER MAINLAND CUSTOMERS		CASE 2: POWER SMART SAVINGS FROM EAST KOOTENAY CUSTOMERS	
				Cost of Electricity c/kW.h	Annual Benefits k$	Cost of Electricity c/kW.h	Annual Benefits k$
90/91	6500	5525	10	2.0	201	1.7	170
91/92	13000	11050	30	2.0	603	1.7	510
92/93	15000	12750	50	2.0	1005	1.7	850
93/94	17000	14450	90	2.3	2070	1.8	1620
94/95	18000	15300	150	2.5	3750	1.8	2700
95/96	17000	14450	250	2.8	7000	1.9	4750
96/97	18000	15300	300	3.2	9600	2.3	6900
97/98	20000	17000	380	3.7	14060	2.7	10260
98/99	21000	17850	460	4.0	18446	3.0	13846
99/00	22000	18700	530	4.5	23850	3.5	18550
00/01	19000	16150	550	5.0	27555	4.0	22055
01/02	10000	8500	550	5.5	30250	4.4	24200
02/03	9000	7650	550	6.4	35200	5.3	29150
03/04	8000	6800	550	6.4	35200	5.3	29150
04/05	8000	6800	550	6.4	35200	5.3	29150
05/06	7000	5950	550	6.4	35200	5.3	29150
06/07	6000	5100	550	6.4	35200	5.3	29150
07/08	5500	4675	550	6.4	35200	5.3	29150
08/09	5000	4250	550	6.4	35200	5.3	29150
09/10	4500	3825	550	6.4	35200	5.3	29150
Present worth at 8% discount rate:	134374	114218	2966		147618		117970

TOTAL RESOURCE COST TEST: present worth of TOTAL COSTS reduced by 15% environmental credit is less than present worth of TOTAL BENEFITS.

RESULT: THIS POWER SMART PROGRAM PASSES THE SCREENING TEST IN BOTH REGIONS.

APPENDIX C COMPUTATION OF LEVELIZED COSTS

Levelizing is a technique to convert a series of non-uniform annual payments to an equivalent uniform annual payment. It is an averaging technique which takes into account the time value of the annual payments.

The technique is illustrated in the following example which levelizes the cost of new firm energy supply over the 10 year period starting in 1993/94 (from Exhibit 1) assuming an 8% net-of-inflation discount rate:

Year:	1	2	3	4	5	6	7	8	9	10
Cost:	1.8¢	1.8	1.9	2.2	2.6	2.9	3.4	3.9	4.4	5.3

$$PW(Costs) = 1.8/(1+.08)^1 + 1.8/(1+.08)^2 + 1.9/(1+.08)^3 + 2.2/(1+.08)^4 + \ldots\ldots + 5.3/(1+.08)^{10}$$

The total present worth of the annual costs over the 10 year period, at 8%, is 18.68¢. Exhibit C-1 provides the present worth factors used to calculate the present worth of the annual costs at an 8% discount rate.

The "levelized" cost is the uniform annual payment (ie. annuity payment) which would also have a total present worth over 10 years, at 8%, of 18.68¢. That is calculated using the "capital recovery factor", which is:

$$\frac{i}{1-(1+i)^{-n}}$$

where:

i is the selected discount rate,

n is the selected number of time periods.

Exhibit C-1 provides the capital recovery factor for 8% for time periods of 1 to 100 years. The capital recovery factor for an 8% discount rate and an annuity paid over 10 years is 0.14903. Therefore, the levelized annual cost of new firm energy over 10 years starting in 1992 is (18.68x0.14903)= 2.78¢.

Exhibit C-2 provides levelized values at 8% for the cost of new firm energy, capacity and electricity delivered to the Lower Mainland for a range of time periods. Exhibits C-3 through 9 provide the levelized costs of new firm energy, capacity and electricity for the other 7 regions. The levelized value of secondary delivered to the Lower Mainland is provided in Exhibit C-10. The value of secondary energy can be readily determined for the other 7 regions by adjusting the Lower Mainland values by the avoided transmission losses using Exhibit 3.

Note: Levelized costs should only be used to evaluate the output of a project if that output is constant over the time period being considered.

EXHIBIT C-1

PRESENT WORTH FACTORS AND CAPITAL RECOVERY FACTOR FOR AN 8% DISCOUNT RATE

n-years	Present Worth Factor $\frac{1}{(1+i)^n}$	Capital Recovery Factor $\frac{i}{1-(1+i)^{-n}}$	n-years	Present Worth Factor $\frac{1}{(1+i)^n}$	Capital Recovery Factor $\frac{i}{1-(1+i)^{-n}}$
1	0.9259	1.080 00	26	0.1352	0.092 51
2	0.8573	0.560 77	27	0.1252	0.091 45
3	0.7938	0.388 03	28	0.1159	0.090 49
4	0.7350	0.301 92	29	0.1073	0.089 62
5	0.6806	0.250 46	30	0.0994	0.088 83
6	0.6302	0.216 32	31	0.0920	0.088 11
7	0.5835	0.192 07	32	0.0852	0.087 45
8	0.5403	0.174 01	33	0.0789	0.086 85
9	0.5002	0.160 08	34	0.0730	0.086 30
10	0.4632	0.149 03	35	0.0676	0.085 80
11	0.4289	0.140 08	40	0.0460	0.083 86
12	0.3971	0.132 70	45	0.0313	0.082 59
13	0.3677	0.126 52	50	0.0213	0.081 74
14	0.3405	0.121 30	55	0.0145	0.081 18
15	0.3152	0.116 83	60	0.0099	0.080 80
16	0.2919	0.112 98	65	0.0067	0.080 54
17	0.2703	0.109 63	70	0.0046	0.080 37
18	0.2502	0.106 70	75	0.0031	0.080 25
19	0.2317	0.104 13	80	0.0021	0.080 17
20	0.2145	0.101 85	85	0.0014	0.080 12
21	0.1987	0.099 83	90	0.0010	0.080 08
22	0.1839	0.098 03	95	0.0007	0.080 05
23	0.1703	0.096 42	100	0.0005	0.080 04
24	0.1577	0.094 98			
25	0.1460	0.093 68			

EXHIBIT C–2 LOWER MAINLAND REGION

LEVELIZED COST of NEW FIRM ENERGY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.8	1.8	1.8	1.8	1.8	2.1	2.7	3.0	3.2	3.3	3.4	3.4	3.4	3.5	3.5
1991/92	1.8	1.8	1.8	1.8	1.8	2.3	2.9	3.2	3.4	3.5	3.5	3.6	3.6	3.6	3.6
1992/93	1.8	1.8	1.8	1.8	1.9	2.5	3.1	3.4	3.5	3.6	3.7	3.7	3.7	3.8	3.8
1993/94	1.8	1.8	1.8	1.9	2.0	2.8	3.3	3.6	3.7	3.8	3.9	3.9	3.9	3.9	3.9
1994/95	1.8	1.8	2.0	2.1	2.2	3.1	3.6	3.8	3.9	4.0	4.0	4.1	4.1	4.1	4.1
1995/96	1.9	2.0	2.2	2.4	2.5	3.4	3.8	4.0	4.1	4.2	4.2	4.3	4.3	4.3	4.3
1996/97	2.2	2.4	2.5	2.7	2.9	3.8	4.1	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.5
1997/98	2.6	2.7	2.9	3.2	3.4	4.2	4.4	4.5	4.6	4.6	4.6	4.7	4.7	4.7	4.7
1998/99	2.9	3.1	3.4	3.6	3.9	4.5	4.6	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8
1999/00	3.4	3.6	3.9	4.2	4.4	4.8	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2000/01	3.9	4.1	4.5	4.7	4.8	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
2001/02	4.4	4.8	5.0	5.0	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
2002/03+	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3

LEVELIZED COST of NEW CAPACITY by TERM ($/kW/yr)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	12	12	12	14	18	32	38	40	42	42	43	43	44	44	44
1991/92	12	12	15	20	24	37	41	43	45	45	46	46	46	46	47
1992/93	12	17	22	28	31	42	45	47	48	48	49	49	49	49	49
1993/94	23	28	34	37	40	47	50	51	51	52	52	52	52	52	52
1994/95	34	40	43	45	48	52	53	54	54	54	54	54	55	55	55
1995/96	46	48	50	52	53	55	56	56	56	56	56	56	56	56	56
1996/97	50	52	54	55	55	56	57	57	57	57	57	57	57	57	57
1997/98	54	56	57	57	57	57	58	58	58	58	58	58	58	58	58
1998/99+	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58

LEVELIZED COST of NEW ELECTRICITY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	2.0	2.0	2.0	2.1	2.1	2.7	3.4	3.8	4.0	4.1	4.2	4.2	4.3	4.3	4.3
1991/92	2.0	2.0	2.1	2.2	2.3	3.0	3.7	4.0	4.2	4.3	4.4	4.4	4.5	4.5	4.5
1992/93	2.0	2.1	2.3	2.4	2.5	3.3	4.0	4.3	4.5	4.6	4.6	4.7	4.7	4.7	4.7
1993/94	2.3	2.4	2.5	2.7	2.8	3.7	4.3	4.6	4.7	4.8	4.9	4.9	4.9	4.9	5.0
1994/95	2.5	2.6	2.8	3.0	3.2	4.1	4.6	4.8	5.0	5.0	5.1	5.1	5.1	5.1	5.2
1995/96	2.8	3.0	3.2	3.4	3.6	4.5	4.9	5.1	5.2	5.3	5.3	5.3	5.4	5.4	5.4
1996/97	3.2	3.4	3.6	3.8	4.0	4.9	5.2	5.4	5.5	5.5	5.5	5.6	5.6	5.6	5.6
1997/98	3.7	3.8	4.0	4.3	4.5	5.3	5.5	5.6	5.7	5.7	5.7	5.8	5.8	5.8	5.8
1998/99	4.0	4.2	4.5	4.7	5.0	5.6	5.7	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9
1999/00	4.5	4.7	5.0	5.3	5.5	5.9	6.0	6.0	6.1	6.1	6.1	6.1	6.1	6.1	6.1
2000/01	5.0	5.2	5.6	5.8	5.9	6.1	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
2001/02	5.5	5.9	6.1	6.1	6.2	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
2002/03+	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4

All values are in October 1990 $'s **Discount Rate 8.0% Net**

EXHIBIT C-3 NORTH COAST REGION

LEVELIZED COST of NEW FIRM ENERGY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.7	1.7	1.7	1.7	1.7	2.0	2.5	2.8	3.0	3.1	3.2	3.2	3.3	3.3	3.3
1991/92	1.7	1.7	1.7	1.7	1.7	2.1	2.7	3.0	3.2	3.3	3.3	3.4	3.4	3.4	3.4
1992/93	1.7	1.7	1.7	1.7	1.8	2.3	2.9	3.2	3.3	3.4	3.5	3.5	3.5	3.5	3.6
1993/94	1.7	1.7	1.7	1.8	1.9	2.6	3.1	3.4	3.5	3.6	3.6	3.7	3.7	3.7	3.7
1994/95	1.7	1.7	1.9	2.0	2.1	2.9	3.4	3.6	3.7	3.8	3.8	3.8	3.8	3.9	3.9
1995/96	1.8	1.9	2.1	2.2	2.4	3.2	3.6	3.8	3.9	4.0	4.0	4.0	4.0	4.0	4.1
1996/97	2.1	2.2	2.4	2.6	2.8	3.6	3.9	4.0	4.1	4.2	4.2	4.2	4.2	4.2	4.2
1997/98	2.4	2.5	2.7	3.0	3.2	3.9	4.1	4.2	4.3	4.3	4.4	4.4	4.4	4.4	4.4
1998/99	2.7	2.9	3.2	3.4	3.7	4.2	4.4	4.5	4.5	4.5	4.5	4.5	4.6	4.6	4.6
1999/00	3.2	3.4	3.6	3.9	4.1	4.5	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.7
2000/01	3.7	3.9	4.2	4.4	4.5	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
2001/02	4.1	4.5	4.7	4.7	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2002/03+	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

LEVELIZED COST of NEW CAPACITY by TERM ($/kW/yr)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	0	0	0	1	2	5	6	6	6	7	7	7	7	7	7
1991/92	0	0	2	3	4	6	7	7	7	7	7	7	7	7	7
1992/93	0	2	4	5	6	7	7	8	8	8	8	8	8	8	8
1993/94	5	6	7	7	7	8	8	8	8	8	8	8	8	9	9
1994/95	8	8	8	8	8	9	9	9	9	9	9	9	9	9	9
1995/96	8	8	8	8	9	9	9	9	9	9	9	9	9	9	9
1996/97	8	8	9	9	9	9	9	9	9	9	9	9	9	9	9
1997/98	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
1998/99+	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9

LEVELIZED COST of NEW ELECTRICITY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.7	1.7	1.7	1.7	1.7	2.1	2.6	3.0	3.1	3.2	3.3	3.4	3.4	3.4	3.4
1991/92	1.7	1.7	1.7	1.7	1.8	2.2	2.8	3.1	3.3	3.4	3.5	3.5	3.5	3.5	3.6
1992/93	1.7	1.7	1.8	1.8	1.9	2.5	3.1	3.3	3.5	3.6	3.6	3.7	3.7	3.7	3.7
1993/94	1.8	1.8	1.8	1.9	2.0	2.8	3.3	3.5	3.7	3.8	3.8	3.8	3.9	3.9	3.9
1994/95	1.8	1.8	2.0	2.1	2.2	3.1	3.5	3.8	3.9	3.9	4.0	4.0	4.0	4.0	4.1
1995/96	1.9	2.0	2.2	2.4	2.5	3.4	3.8	4.0	4.1	4.1	4.2	4.2	4.2	4.2	4.2
1996/97	2.2	2.4	2.5	2.7	2.9	3.8	4.1	4.2	4.3	4.3	4.4	4.4	4.4	4.4	4.4
1997/98	2.6	2.7	2.9	3.2	3.4	4.1	4.3	4.4	4.5	4.5	4.6	4.6	4.6	4.6	4.6
1998/99	2.9	3.1	3.4	3.6	3.9	4.4	4.6	4.7	4.7	4.7	4.7	4.7	4.8	4.8	4.8
1999/00	3.4	3.6	3.8	4.1	4.3	4.7	4.8	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2000/01	3.9	4.1	4.4	4.6	4.7	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2001/02	4.3	4.7	4.9	4.9	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
2002/03+	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2

All values are in October 1990 $'s **Discount Rate 8.0% Net**

EXHIBIT C–4 PEACE RIVER REGION

LEVELIZED COST of NEW FIRM ENERGY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.7	1.7	1.7	1.7	1.7	2.0	2.5	2.8	3.0	3.1	3.2	3.2	3.3	3.3	3.3
1991/92	1.7	1.7	1.7	1.7	1.7	2.1	2.7	3.0	3.2	3.3	3.3	3.4	3.4	3.4	3.4
1992/93	1.7	1.7	1.7	1.7	1.8	2.3	2.9	3.2	3.3	3.4	3.5	3.5	3.5	3.5	3.6
1993/94	1.7	1.7	1.7	1.8	1.9	2.6	3.1	3.4	3.5	3.6	3.6	3.7	3.7	3.7	3.7
1994/95	1.7	1.7	1.9	2.0	2.1	2.9	3.4	3.6	3.7	3.8	3.8	3.8	3.8	3.9	3.9
1995/96	1.8	1.9	2.1	2.2	2.4	3.2	3.6	3.8	3.9	4.0	4.0	4.0	4.0	4.0	4.1
1996/97	2.1	2.2	2.4	2.6	2.8	3.6	3.9	4.0	4.1	4.2	4.2	4.2	4.2	4.2	4.2
1997/98	2.4	2.5	2.7	3.0	3.2	3.9	4.1	4.2	4.3	4.3	4.4	4.4	4.4	4.4	4.4
1998/99	2.7	2.9	3.2	3.4	3.7	4.2	4.4	4.5	4.5	4.5	4.5	4.5	4.6	4.6	4.6
1999/00	3.2	3.4	3.6	3.9	4.1	4.5	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.7
2000/01	3.7	3.9	4.2	4.4	4.5	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
2001/02	4.1	4.5	4.7	4.7	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2002/03+	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

LEVELIZED COST of NEW CAPACITY by TERM ($/kW/yr)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	0	0	0	0	2	7	8	9	9	10	10	10	10	10	10
1991/92	0	0	1	2	4	8	9	10	10	11	11	11	11	11	11
1992/93	0	1	3	6	7	10	11	11	11	12	12	12	12	12	12
1993/94	2	5	8	9	10	12	12	12	12	13	13	13	13	13	13
1994/95	8	11	12	12	13	13	13	13	13	14	14	14	14	14	14
1995/96	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
1996/97	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
1997/98	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
1998/99+	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14

LEVELIZED COST of NEW ELECTRICITY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.7	1.7	1.7	1.7	1.7	2.1	2.7	3.0	3.2	3.3	3.4	3.4	3.4	3.5	3.5
1991/92	1.7	1.7	1.7	1.7	1.8	2.3	2.9	3.2	3.4	3.5	3.5	3.6	3.6	3.6	3.6
1992/93	1.7	1.7	1.7	1.8	1.9	2.5	3.1	3.4	3.6	3.6	3.7	3.7	3.8	3.8	3.8
1993/94	1.7	1.7	1.9	2.0	2.1	2.8	3.4	3.6	3.7	3.8	3.9	3.9	3.9	3.9	4.0
1994/95	1.8	1.9	2.1	2.2	2.3	3.2	3.6	3.8	4.0	4.0	4.1	4.1	4.1	4.1	4.2
1995/96	2.1	2.2	2.4	2.5	2.7	3.5	3.9	4.1	4.2	4.2	4.3	4.3	4.3	4.3	4.3
1996/97	2.3	2.5	2.6	2.8	3.0	3.9	4.2	4.3	4.4	4.4	4.5	4.5	4.5	4.5	4.5
1997/98	2.7	2.8	3.0	3.2	3.4	4.2	4.4	4.5	4.6	4.6	4.7	4.7	4.7	4.7	4.7
1998/99	3.0	3.2	3.4	3.7	3.9	4.5	4.7	4.7	4.8	4.8	4.8	4.8	4.9	4.9	4.9
1999/00	3.5	3.7	3.9	4.2	4.4	4.8	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2000/01	3.9	4.1	4.5	4.7	4.8	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
2001/02	4.4	4.8	5.0	5.0	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
2002/03+	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3

All values are in October 1990 $'s **Discount Rate 8.0% Net**

EXHIBIT C–5 EAST KOOTENAY REGION

LEVELIZED COST of NEW FIRM ENERGY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.7	1.7	1.7	1.7	1.7	2.0	2.5	2.8	3.0	3.1	3.2	3.2	3.3	3.3	3.3
1991/92	1.7	1.7	1.7	1.7	1.7	2.1	2.7	3.0	3.2	3.3	3.3	3.4	3.4	3.4	3.4
1992/93	1.7	1.7	1.7	1.7	1.8	2.3	2.9	3.2	3.3	3.4	3.5	3.5	3.5	3.5	3.6
1993/94	1.7	1.7	1.7	1.8	1.9	2.6	3.1	3.4	3.5	3.6	3.6	3.7	3.7	3.7	3.7
1994/95	1.7	1.7	1.9	2.0	2.1	2.9	3.4	3.6	3.7	3.8	3.8	3.8	3.8	3.9	3.9
1995/96	1.8	1.9	2.1	2.2	2.4	3.2	3.6	3.8	3.9	4.0	4.0	4.0	4.0	4.0	4.1
1996/97	2.1	2.2	2.4	2.6	2.8	3.6	3.9	4.0	4.1	4.2	4.2	4.2	4.2	4.2	4.2
1997/98	2.4	2.5	2.7	3.0	3.2	3.9	4.1	4.2	4.3	4.3	4.4	4.4	4.4	4.4	4.4
1998/99	2.7	2.9	3.2	3.4	3.7	4.2	4.4	4.5	4.5	4.5	4.5	4.5	4.6	4.6	4.6
1999/00	3.2	3.4	3.6	3.9	4.1	4.5	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.7
2000/01	3.7	3.9	4.2	4.4	4.5	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
2001/02	4.1	4.5	4.7	4.7	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2002/03+	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

LEVELIZED COST of NEW CAPACITY by TERM ($/kW/yr)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	0	0	0	1	2	6	8	9	9	10	10	10	10	10	10
1991/92	0	0	1	2	3	7	9	10	10	10	11	11	11	11	11
1992/93	0	2	3	4	5	9	10	11	11	11	11	12	12	12	12
1993/94	4	5	6	7	8	11	12	12	12	12	12	13	13	13	13
1994/95	6	7	8	9	10	12	13	13	13	13	13	13	13	13	13
1995/96	8	9	10	11	12	13	13	14	14	14	14	14	14	14	14
1996/97	10	11	12	13	13	14	14	14	14	14	14	14	14	14	14
1997/98	12	13	14	14	14	15	15	15	15	15	15	15	15	15	15
1998/99+	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15

LEVELIZED COST of NEW ELECTRICITY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.7	1.7	1.7	1.7	1.7	2.1	2.7	3.0	3.2	3.3	3.4	3.4	3.4	3.5	3.5
1991/92	1.7	1.7	1.7	1.7	1.8	2.3	2.9	3.2	3.4	3.5	3.5	3.6	3.6	3.6	3.6
1992/93	1.7	1.7	1.8	1.8	1.9	2.5	3.1	3.4	3.6	3.6	3.7	3.7	3.8	3.8	3.8
1993/94	1.8	1.8	1.8	1.9	2.1	2.8	3.4	3.6	3.7	3.8	3.9	3.9	3.9	3.9	4.0
1994/95	1.8	1.8	2.0	2.1	2.3	3.2	3.6	3.8	4.0	4.0	4.1	4.1	4.1	4.1	4.1
1995/96	1.9	2.1	2.3	2.4	2.6	3.5	3.9	4.1	4.2	4.2	4.3	4.3	4.3	4.3	4.3
1996/97	2.3	2.5	2.6	2.8	3.0	3.9	4.2	4.3	4.4	4.4	4.5	4.5	4.5	4.5	4.5
1997/98	2.7	2.8	3.0	3.3	3.5	4.2	4.4	4.5	4.6	4.6	4.7	4.7	4.7	4.7	4.7
1998/99	3.0	3.2	3.5	3.7	4.0	4.5	4.7	4.8	4.8	4.8	4.8	4.8	4.9	4.9	4.9
1999/00	3.5	3.7	3.9	4.2	4.4	4.8	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2000/01	4.0	4.2	4.5	4.7	4.8	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
2001/02	4.4	4.8	5.0	5.0	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
2002/03+	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3

All values are in October 1990 $'s **Discount Rate 8.0% Net**

EXHIBIT C-6 CENTRAL INTERIOR REGION

LEVELIZED COST of NEW FIRM ENERGY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.7	1.7	1.7	1.7	1.7	2.0	2.6	2.9	3.1	3.2	3.2	3.3	3.3	3.3	3.4
1991/92	1.7	1.7	1.7	1.7	1.7	2.2	2.8	3.1	3.2	3.3	3.4	3.4	3.4	3.5	3.5
1992/93	1.7	1.7	1.7	1.7	1.8	2.4	3.0	3.2	3.4	3.5	3.5	3.6	3.6	3.6	3.6
1993/94	1.7	1.7	1.7	1.8	1.9	2.7	3.2	3.4	3.6	3.6	3.7	3.7	3.7	3.8	3.8
1994/95	1.7	1.7	1.9	2.0	2.1	3.0	3.4	3.6	3.8	3.8	3.9	3.9	3.9	3.9	4.0
1995/96	1.8	1.9	2.1	2.3	2.4	3.3	3.7	3.9	4.0	4.0	4.1	4.1	4.1	4.1	4.1
1996/97	2.1	2.3	2.4	2.6	2.8	3.7	4.0	4.1	4.2	4.2	4.3	4.3	4.3	4.3	4.3
1997/98	2.5	2.6	2.8	3.0	3.2	4.0	4.2	4.3	4.4	4.4	4.5	4.5	4.5	4.5	4.5
1998/99	2.8	3.0	3.2	3.5	3.7	4.3	4.5	4.5	4.6	4.6	4.6	4.6	4.7	4.7	4.7
1999/00	3.3	3.5	3.7	4.0	4.2	4.6	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8
2000/01	3.7	3.9	4.3	4.5	4.6	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2001/02	4.2	4.6	4.8	4.8	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2002/03+	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1

LEVELIZED COST of NEW CAPACITY by TERM ($/kW/yr)

Term in Year	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	0	0	0	2	4	12	15	17	18	18	18	19	19	19	19
1991/92	0	0	2	5	8	15	17	19	19	20	20	20	20	20	20
1992/93	0	3	7	10	12	18	20	21	21	22	22	22	22	22	22
1993/94	7	10	14	16	17	21	22	23	23	24	24	24	24	24	24
1994/95	14	17	19	20	22	24	24	25	25	25	25	25	25	25	25
1995/96	21	22	23	24	24	25	26	26	26	26	26	26	26	26	26
1996/97	23	24	25	25	26	26	26	26	26	27	27	27	27	27	27
1997/98	25	26	26	26	27	27	27	27	27	27	27	27	27	27	27
1998/99+	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27

LEVELIZED COST of NEW ELECTRICITY by TERM (c/kWh)

Term in Year	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.7	1.7	1.7	1.7	1.8	2.2	2.9	3.2	3.4	3.5	3.6	3.6	3.7	3.7	3.7
1991/92	1.7	1.7	1.8	1.8	1.9	2.5	3.1	3.4	3.6	3.7	3.8	3.8	3.8	3.9	3.9
1992/93	1.7	1.8	1.9	1.9	2.0	2.7	3.4	3.6	3.8	3.9	4.0	4.0	4.0	4.0	4.1
1993/94	1.9	1.9	2.0	2.2	2.3	3.1	3.6	3.9	4.0	4.1	4.2	4.2	4.2	4.2	4.2
1994/95	2.0	2.1	2.3	2.4	2.6	3.4	3.9	4.1	4.2	4.3	4.4	4.4	4.4	4.4	4.4
1995/96	2.2	2.4	2.6	2.7	2.9	3.8	4.2	4.4	4.5	4.5	4.6	4.6	4.6	4.6	4.6
1996/97	2.6	2.8	2.9	3.1	3.3	4.2	4.5	4.6	4.7	4.7	4.8	4.8	4.8	4.8	4.8
1997/98	3.0	3.1	3.3	3.6	3.8	4.5	4.7	4.8	4.9	4.9	5.0	5.0	5.0	5.0	5.0
1998/99	3.3	3.5	3.8	4.0	4.3	4.8	5.0	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.2
1999/00	3.8	4.0	4.2	4.5	4.7	5.1	5.2	5.2	5.3	5.3	5.3	5.3	5.3	5.3	5.3
2000/01	4.3	4.5	4.8	5.0	5.1	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
2001/02	4.7	5.1	5.3	5.3	5.4	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
2002/03+	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6

All values are in October 1990 $'s **Discount Rate 8.0% Net**

EXHIBIT C–7 SOUTH INTERIOR REGION

LEVELIZED COST of NEW FIRM ENERGY by TERM (c/kWh)

Term in Year	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.7	1.7	1.7	1.7	1.7	2.0	2.6	2.9	3.1	3.2	3.2	3.3	3.3	3.3	3.4
1991/92	1.7	1.7	1.7	1.7	1.7	2.2	2.8	3.1	3.2	3.3	3.4	3.4	3.4	3.5	3.5
1992/93	1.7	1.7	1.7	1.7	1.8	2.4	3.0	3.2	3.4	3.5	3.5	3.6	3.6	3.6	3.6
1993/94	1.7	1.7	1.7	1.8	1.9	2.7	3.2	3.4	3.6	3.6	3.7	3.7	3.7	3.8	3.8
1994/95	1.7	1.7	1.9	2.0	2.1	3.0	3.4	3.6	3.8	3.8	3.9	3.9	3.9	3.9	4.0
1995/96	1.8	1.9	2.1	2.3	2.4	3.3	3.7	3.9	4.0	4.0	4.1	4.1	4.1	4.1	4.1
1996/97	2.1	2.3	2.4	2.6	2.8	3.7	4.0	4.1	4.2	4.2	4.3	4.3	4.3	4.3	4.3
1997/98	2.5	2.6	2.8	3.0	3.2	4.0	4.2	4.3	4.4	4.4	4.5	4.5	4.5	4.5	4.5
1998/99	2.8	3.0	3.2	3.5	3.7	4.3	4.5	4.5	4.6	4.6	4.6	4.6	4.7	4.7	4.7
1999/00	3.3	3.5	3.7	4.0	4.2	4.6	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8
2000/01	3.7	3.9	4.3	4.5	4.6	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2001/02	4.2	4.6	4.8	4.8	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2002/03+	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1

LEVELIZED COST of NEW CAPACITY by TERM ($/kW/yr)

Term in Year	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	0	0	0	1	2	9	13	15	16	16	16	17	17	17	17
1991/92	0	0	1	3	5	12	15	16	17	18	18	18	18	18	18
1992/93	0	2	4	6	8	15	17	18	19	19	20	20	20	20	20
1993/94	4	6	8	10	12	18	20	20	21	21	21	21	21	21	22
1994/95	9	11	13	15	17	20	22	22	22	22	23	23	23	23	23
1995/96	13	15	17	19	20	22	23	24	24	24	24	24	24	24	24
1996/97	17	19	21	22	23	24	25	25	25	25	25	25	25	25	25
1997/98	21	23	24	25	25	25	25	26	26	26	26	26	26	26	26
1998/99+	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26

LEVELIZED COST of NEW ELECTRICITY by TERM (c/kWh)

Term in Year	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.7	1.7	1.7	1.7	1.8	2.2	2.8	3.2	3.4	3.5	3.6	3.6	3.6	3.7	3.7
1991/92	1.7	1.7	1.7	1.8	1.8	2.4	3.0	3.4	3.6	3.7	3.7	3.8	3.8	3.8	3.8
1992/93	1.7	1.7	1.8	1.9	2.0	2.7	3.3	3.6	3.8	3.9	3.9	3.9	4.0	4.0	4.0
1993/94	1.8	1.8	1.9	2.0	2.2	3.0	3.6	3.8	4.0	4.1	4.1	4.1	4.2	4.2	4.2
1994/95	1.9	2.0	2.1	2.3	2.5	3.4	3.9	4.1	4.2	4.3	4.3	4.3	4.4	4.4	4.4
1995/96	2.1	2.2	2.4	2.6	2.8	3.7	4.1	4.3	4.4	4.5	4.5	4.6	4.6	4.6	4.6
1996/97	2.4	2.6	2.8	3.1	3.3	4.1	4.4	4.6	4.7	4.7	4.7	4.8	4.8	4.8	4.8
1997/98	2.9	3.1	3.3	3.5	3.7	4.5	4.7	4.8	4.9	4.9	5.0	5.0	5.0	5.0	5.0
1998/99	3.3	3.5	3.7	4.0	4.2	4.8	5.0	5.0	5.1	5.1	5.1	5.1	5.2	5.2	5.2
1999/00	3.8	4.0	4.2	4.5	4.7	5.1	5.2	5.2	5.3	5.3	5.3	5.3	5.3	5.3	5.3
2000/01	4.2	4.4	4.8	5.0	5.1	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
2001/02	4.7	5.1	5.3	5.3	5.4	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
2002/03+	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6

All values are in October 1990 $'s

Discount Rate 8.0% Net

EXHIBIT C–8 KELLY LAKE/NICOLA REGION

LEVELIZED COST of NEW FIRM ENERGY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.8	1.8	1.8	1.8	1.8	2.1	2.6	3.0	3.1	3.3	3.3	3.4	3.4	3.4	3.4
1991/92	1.8	1.8	1.8	1.8	1.8	2.2	2.8	3.1	3.3	3.4	3.5	3.5	3.5	3.5	3.6
1992/93	1.8	1.8	1.8	1.8	1.9	2.4	3.0	3.3	3.5	3.6	3.6	3.7	3.7	3.7	3.7
1993/94	1.8	1.8	1.8	1.9	2.0	2.7	3.3	3.5	3.6	3.7	3.8	3.8	3.8	3.8	3.9
1994/95	1.8	1.8	2.0	2.1	2.2	3.0	3.5	3.7	3.8	3.9	4.0	4.0	4.0	4.0	4.0
1995/96	1.9	2.0	2.2	2.3	2.5	3.4	3.8	4.0	4.1	4.1	4.2	4.2	4.2	4.2	4.2
1996/97	2.2	2.3	2.5	2.7	2.9	3.7	4.0	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4
1997/98	2.5	2.6	2.8	3.1	3.3	4.1	4.3	4.4	4.5	4.5	4.5	4.6	4.6	4.6	4.6
1998/99	2.8	3.0	3.3	3.5	3.8	4.4	4.5	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.7
1999/00	3.3	3.5	3.8	4.1	4.3	4.7	4.8	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2000/01	3.8	4.0	4.4	4.6	4.7	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2001/02	4.3	4.7	4.9	4.9	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
2002/03+	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2

LEVELIZED COST of NEW CAPACITY by TERM ($/kW/yr)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	0	0	0	2	5	16	21	23	25	26	26	26	27	27	27
1991/92	0	0	3	6	9	20	24	26	27	28	28	29	29	29	29
1992/93	0	5	8	11	14	24	28	29	30	30	31	31	31	31	31
1993/94	10	13	16	18	21	29	31	32	33	33	34	34	34	34	34
1994/95	16	19	22	24	27	32	34	35	35	35	36	36	36	36	36
1995/96	22	25	28	30	32	35	36	37	37	37	37	37	37	37	37
1996/97	28	31	34	35	36	38	38	38	38	39	39	39	39	39	39
1997/98	34	37	38	38	39	39	39	39	39	40	40	40	40	40	40
1998/99+	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40

LEVELIZED COST of NEW ELECTRICITY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.8	1.8	1.8	1.8	1.9	2.4	3.1	3.4	3.6	3.8	3.8	3.9	3.9	3.9	4.0
1991/92	1.8	1.8	1.9	1.9	2.0	2.6	3.3	3.7	3.8	4.0	4.0	4.1	4.1	4.1	4.1
1992/93	1.8	1.9	2.0	2.0	2.1	2.9	3.6	3.9	4.1	4.2	4.2	4.3	4.3	4.3	4.3
1993/94	2.0	2.0	2.1	2.3	2.4	3.3	3.9	4.2	4.3	4.4	4.4	4.5	4.5	4.5	4.5
1994/95	2.1	2.2	2.4	2.5	2.7	3.7	4.2	4.4	4.5	4.6	4.7	4.7	4.7	4.7	4.7
1995/96	2.3	2.5	2.7	2.9	3.1	4.1	4.5	4.7	4.8	4.9	4.9	4.9	4.9	4.9	5.0
1996/97	2.7	2.9	3.1	3.4	3.6	4.5	4.8	5.0	5.0	5.1	5.1	5.1	5.2	5.2	5.2
1997/98	3.2	3.4	3.6	3.8	4.0	4.8	5.1	5.2	5.3	5.3	5.3	5.3	5.4	5.4	5.4
1998/99	3.6	3.8	4.1	4.3	4.6	5.2	5.3	5.4	5.5	5.5	5.5	5.5	5.5	5.5	5.5
1999/00	4.1	4.3	4.6	4.9	5.1	5.5	5.6	5.6	5.7	5.7	5.7	5.7	5.7	5.7	5.7
2000/01	4.6	4.8	5.2	5.4	5.5	5.7	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
2001/02	5.1	5.5	5.7	5.7	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
2002/03+	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0

All values are in October 1990 $'s **Discount Rate 8.0% Net**

EXHIBIT C–9 VANCOUVER ISLAND REGION

LEVELIZED COST of NEW FIRM ENERGY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	1.8	1.8	1.8	1.8	1.8	2.1	2.7	3.0	3.2	3.3	3.4	3.4	3.4	3.5	3.5
1991/92	1.8	1.8	1.8	1.8	1.8	2.3	2.9	3.2	3.4	3.5	3.5	3.6	3.6	3.6	3.6
1992/93	1.8	1.8	1.8	1.8	1.9	2.5	3.1	3.4	3.5	3.6	3.7	3.7	3.7	3.8	3.8
1993/94	1.8	1.8	1.8	1.9	2.0	2.8	3.3	3.6	3.7	3.8	3.9	3.9	3.9	3.9	3.9
1994/95	1.8	1.8	2.0	2.1	2.2	3.1	3.6	3.8	3.9	4.0	4.0	4.1	4.1	4.1	4.1
1995/96	1.9	2.0	2.2	2.4	2.5	3.4	3.8	4.0	4.1	4.2	4.2	4.3	4.3	4.3	4.3
1996/97	2.2	2.4	2.5	2.7	2.9	3.8	4.1	4.3	4.4	4.4	4.4	4.5	4.5	4.5	4.5
1997/98	2.6	2.7	2.9	3.2	3.4	4.2	4.4	4.5	4.6	4.6	4.6	4.7	4.7	4.7	4.7
1998/99	2.9	3.1	3.4	3.6	3.9	4.5	4.6	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8
1999/00	3.4	3.6	3.9	4.2	4.4	4.8	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2000/01	3.9	4.1	4.5	4.7	4.8	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
2001/02	4.4	4.8	5.0	5.0	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
2002/03+	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3

LEVELIZED COST of NEW CAPACITY by TERM ($/kW/yr)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	12	12	12	15	18	33	41	48	52	54	55	56	57	57	58
1991/92	12	12	16	20	25	39	46	52	56	58	59	60	61	61	62
1992/93	12	18	23	29	33	44	52	58	61	62	64	64	65	65	66
1993/94	24	30	36	40	43	50	58	63	66	67	68	69	69	70	70
1994/95	36	42	46	48	50	55	64	68	70	71	72	73	73	73	74
1995/96	49	51	53	55	56	60	68	72	74	75	75	76	76	76	77
1996/97	53	55	57	58	58	64	71	74	76	77	78	78	78	79	79
1997/98	57	59	60	60	60	68	74	77	79	79	80	80	81	81	81
1998/99+	61	61	61	61	61	72	77	80	81	82	82	82	83	83	83

LEVELIZED COST of NEW ELECTRICITY by TERM (c/kWh)

Term in Years	1	2	3	4	5	10	15	20	25	30	35	40	45	50	70
Start: 1990/91	2.0	2.0	2.0	2.1	2.1	2.7	3.5	3.9	4.2	4.4	4.5	4.5	4.6	4.6	4.6
1991/92	2.0	2.0	2.1	2.2	2.3	3.0	3.8	4.2	4.5	4.6	4.7	4.7	4.8	4.8	4.8
1992/93	2.0	2.1	2.3	2.4	2.5	3.3	4.1	4.5	4.7	4.9	4.9	5.0	5.0	5.0	5.1
1993/94	2.3	2.4	2.6	2.7	2.9	3.8	4.5	4.8	5.0	5.1	5.2	5.2	5.3	5.3	5.3
1994/95	2.5	2.7	2.8	3.0	3.2	4.2	4.8	5.1	5.3	5.4	5.5	5.5	5.5	5.5	5.6
1995/96	2.9	3.0	3.2	3.4	3.6	4.6	5.2	5.4	5.6	5.7	5.7	5.8	5.8	5.8	5.8
1996/97	3.2	3.4	3.6	3.9	4.1	5.1	5.5	5.7	5.9	5.9	6.0	6.0	6.0	6.0	6.1
1997/98	3.7	3.9	4.1	4.3	4.5	5.5	5.9	6.0	6.1	6.2	6.2	6.2	6.3	6.3	6.3
1998/99	4.1	4.3	4.6	4.8	5.1	5.9	6.2	6.3	6.4	6.4	6.4	6.5	6.5	6.5	6.5
1999/00	4.6	4.8	5.1	5.4	5.6	6.2	6.4	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.7
2000/01	5.1	5.3	5.7	5.9	6.1	6.5	6.7	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
2001/02	5.6	6.0	6.2	6.4	6.5	6.8	6.9	6.9	7.0	7.0	7.0	7.0	7.0	7.0	7.0
2002/03+	6.5	6.5	6.7	6.8	6.9	7.0	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1

All values are in October 1990 $'s **Discount Rate 8.0% Net**